RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages are made by comparison of the three and six months ended June 30, 2007 to the three and six months ended June 30, 2006.

Revenues

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	2007	2006	$ Change	% Change	2007	2006	$ Change	% Change
Transmission	315	316	(1)	-	642	614	28	5
Distribution	798	757	41	5	1,742	1,613	129	8
Other	7	5	2	40	14	11	3	27
	1,120	1,078	42	4	2,398	2,238	160	7
Average Ontario 60-minute peak demand *(MW)*[1]	22,414	22,596	(182)	(1)	22,947	22,489	458	2
Distribution - units distributed to customers *(TWh)*[1]	6.9	6.6	0.3	5	15.5	14.6	0.9	6

[1]System-related statistics are preliminary

The demand for electricity generally follows normal weather-related variations, and, therefore, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues, which are primarily attributable to maintenance services provided to generators, and secondary use of our land rights-of-way.

Our transmission tariff revenues were marginally lower during the second quarter of 2007, but increased by $28 million, or 5%, in the first six months compared to the same period last year. Both the three and six month periods reflect a decision issued by the Ontario Energy Board (OEB) on March 30, 2007 ordering that the transmission earnings sharing mechanism cease effective December 31, 2006. This decision had the effect of increasing transmission revenues by $3 million in the quarter and $18 million in the first six months compared to last year. In addition, revenues for the second quarter increased marginally as peak demands were comparable to the same period last year. However, the average monthly peak demand was higher during the first six months of 2007, resulting in increased transmission revenues of $16 million in the year-to-date period. We also experienced lower other revenues of $4 million in the quarter and $6 million on a year-to-date basis.

We are currently awaiting a decision on our transmission rate application which was initially filed in September 2006. On March 30, 2007, the OEB issued an order that we establish a new regulatory deferral account to record any revenue differential between existing transmission rates and the new rates that are anticipated to be approved later this year, effective January 1, 2007. The specifics of this decision cannot be estimated at this time. Appropriate accounting recognition, including an increase or decrease to current revenue levels, will be given to any revenue differential once the OEB renders its decision on our rates.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenue, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $41 million, or 5%, to $798 million in the second quarter and by $129 million, or 8%, to $1,742 million during the first six months compared to the same periods last year. These increases were primarily a result of the recovery of increased purchased power costs of $17 million in the quarter and $60 million in the first six months, as described below under "Purchased Power." In addition, the OEB approved increases in distribution tariff rates for our subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), effective May 1, 2006 and May 1, 2007 respectively. These tariff rate increases of $8 million in the quarter and $42 million in the first six months support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers throughout Ontario, resulted in higher distribution revenues. In 2006, rates were based on a full cost of service hearing and in 2007, rates were adjusted based on the OEB's Second Generation Incentive Regulation mechanism. Higher energy consumption, resulting primarily from the colder winter weather this year, increased our distribution revenues by a further $6 million in the quarter and $15 million in the year-to-date period. In addition, as a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recognized an additional $10 million in revenue. We also experienced marginally higher ancillary revenues of $2 million in the first six months of 2007 compared to the same period last year.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the Independent Electricity System Operator's (IESO's) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's Regulated Price Plan (RPP), which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP is provided below.

Summary of RPP				
	Tier Threshold (kWh)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2005	1,000	750	5.0	5.8
May 1, 2006	600	750	5.8	6.7
November 1, 2006	1,000	750	5.5	6.4
May 1, 2007	600	750	5.3	6.2

Purchased power costs increased by $17 million, or 3%, to $522 million in the second quarter and by $60 million, or 5%, to $1,163 million during the first six months compared to last year. These increases primarily reflect higher demand for electricity of $14 million in the quarter and $48 million in the first six months, and higher wholesale commodity prices for customers who are not eligible for the RPP of $10 million, both in the quarter and during the first six months. For the quarter, these increases were partially offset by the impact of the May 1, 2007 RPP rate change for residential and other eligible customers and a reduction in wholesale market service charges levied by the IESO.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	**2007**	**2006**	**$ Change**	**% Change**	**2007**	**2006**	**$ Change**	**% Change**
Transmission	107	109	(2)	(2)	206	202	4	2
Distribution	145	120	25	21	273	206	67	33
Other	7	5	2	40	14	11	3	27
	259	234	25	11	493	419	74	18

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $2 million, or by 2%, in the quarter and increased by $4 million, or 2%, on a year-to-date basis compared to the same periods last year. Within our work programs, we continued our investments that support the safe and reliable operation of the transmission system. We experienced higher work program expenditures in the quarter of approximately $7 million and year-to-date of about $9 million, primarily due to the early mobilization of resources for our planned station maintenance program. For the year-to-date period, these expenditures were partially offset by lower line clearing and brush control expenditures experienced in the first quarter. In addition, expenditures incurred in support of the transmission system increased marginally during the first six months as we commenced a major business systems and processes project. These increases were substantially offset in the quarter and in the year-to-date periods by the impact of reassigning resources in support of our larger capital work program.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage system increased by $25 million, or 21%, in the second quarter and by $67 million, or 33%, on a year-to-date basis, relative to the comparative periods. Higher expenditures within our work program of $16 million in the quarter and $49 million for the first six months resulted from higher line clearing and brush control expenditures, customer participation in our conservation and demand management programs and higher planned maintenance in our lines work program. In addition, pension costs within our distribution business for the quarterly and year-to-date periods were impacted by a 2006 OEB rate decision. Prior to May 1, 2006, all of our distribution-related pension costs were deferred as a regulatory asset. Also, as a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recognized an additional $10 million in expenditures associated with this program. In addition to these increases, our other support expenditures for the first six months increased marginally, as a result of the commencement of a major business systems and processes project.

Depreciation and Amortization

Depreciation and amortization increased by $2 million, or 2%, to $129 million in the second quarter and by $9 million, or 4%, to $254 million in the first six months compared to the same periods last year. These increases were primarily the result of higher fixed asset removal costs related to storm recovery work in our lines work program and, for the year-to-date period, higher amortization of our regulatory assets resulting from the April 12, 2006 OEB rate decision that was effective on May 1, 2006.

Financing Charges

Financing charges in both the second quarter and year-to-date periods increased by $1 million to $74 million and to $147 million respectively, compared to the same periods last year. These increases were primarily due to reduced capitalization of financing costs on our regulatory accounts of $4 million in the quarter and $6 million for the first six months. Interest related to a first quarter 2006 recovery of payments in lieu of corporate income taxes also contributed to the increase in year-over-year financing costs for the six month period. The impact of these increases was almost offset by lower interest on long-term debt reflecting the impact of lower average borrowing costs, partially offset by a higher average level of debt outstanding.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes increased by $3 million, or 8%, to $43 million in the second quarter and increased by $25 million, or 34%, to $99 million on a year-to-date basis, compared to the same periods last year. The increase in the quarter was primarily attributable to minor temporary differences. The year-to-date increase primarily reflects higher pre-tax income in the first six months of this year and the impact of last year's first quarter recognition of a $30 million tax benefit related to the recovery of payments in lieu of corporate taxes from prior years.

Net Income

Net income of $93 million was lower by $6 million, or 6% in the second quarter, and lower by $9 million, or 4% in the first six months compared to 2006 results. These reductions reflect increased expenditures within our distribution work program to maintain system reliability and the impact of a 2006 OEB decision on our distribution-related pension expenditures. In addition, our effective tax rate was higher in the year-to-date period due to a recovery of payments in lieu of corporate income taxes in the first quarter of last year. These increases were partially offset by increased tariff revenues within our transmission and distribution businesses.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters from September 30, 2005 through June 30, 2007. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2007			2006				2005
Quarter ended	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**
Total revenue[1, 2, 3, 4]	1,120	1,278	1,142	1,165	1,078	1,160	1,025	1,179
Net income[1, 2, 3]	93	149	101	103	99	152	104	133
Net income to common shareholder[1, 2, 3]	88	145	96	99	94	148	99	129

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately $140 million. The application of the one-time credit did not result in any adjustment to net income.

[3] Effective January 1, 2006, the OEB applied an earnings sharing mechanism (ESM) to any transmission earnings in excess of the approved rate of return of 9.88%. On March 30, 2007 the OEB issued a decision ordering that the ESM cease effective December 31, 2006. The approved balance of the ESM account is expected to be incorporated into future rates to be set later in 2007.

[4] As a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recognized an additional $10 million in revenue and cost as at June 30, 2007.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash	**Three months ended June 30**		**Six months ended June 30**	
(Canadian dollars in millions)	**2007**	**2006**	**2007**	**2006**
Operating activities	238	218	537	364
Financing activities				
Long-term debt issued	-	250	400	550
Long-term debt retired	(282)	(448)	(282)	(448)
Short-term notes payable	75	130	15	130
Dividends paid	(73)	(64)	(180)	(223)
Investing activities				
Capital expenditures	(303)	(198)	(490)	(375)
Other financing and investing activities	15	(3)	14	5
Net change in cash and cash equivalents	(330)	(115)	14	3

Operating Activities

Net cash generated from operating activities increased by $20 million to $238 million in the second quarter, and by $173 million to $537 million in the first six months compared to 2006 results, primarily due to lower working capital requirements during the quarter and year-to-date periods. In the quarter, our working capital requirements were impacted by a first quarter 2006 recovery of payments in lieu of corporate income taxes. For the year-to-date period, our working capital requirements also increased as a result of the *Ontario Price Credit* that was provided to RPP customers in early 2006, pursuant to regulation. Funding for the credit was received from the IESO in early December 2005.

Financing Activities

Short-term liquidity is provided through funds from operations and our Commercial Paper Program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. As at June 30, 2007, we had $75 million of short-term notes outstanding. The commercial paper program is supported by a $750 million committed revolving credit facility with a syndicate of banks. The term of this facility has been extended as of August 10th, 2007 to August 10th, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. Long-term financing is provided by our access to the debt markets, including our Medium-Term Note Program. On June 21, 2007, we filed a $2.5 billion base shelf prospectus to renew our Medium-Term Note Program for another 25 months. Our notes and debentures mature between 2007 and 2046. We currently plan to refinance maturing debt principally through our Medium-Term Note Program. The maximum authorised principal amount of medium-term notes issuable under this program is $2,500 million, all of which currently remains available until July 2009.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Inc.	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
Standard & Poor's Rating Services Inc.	A-1	A

We have customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During the second quarter of 2007, we repaid $282 million in maturing long term debt and increased our short-term notes by $75 million. During the same period in 2006, we issued $250 million in long-term debt under our Medium-Term Note Program, repaid $448 million in maturing long-term debt, and increased our short-term notes by $130 million.

During the first six months of 2007, we issued $400 million in long-term debt under our Medium-Term Note Program, repaid $282 million in maturing long-term debt, and increased our short-term notes by $15 million. In comparison, during the same period in 2006, we issued $550 million in long-term debt under our medium term note program, repaid $448 million in maturing long-term debt and increased our short-term notes by $130 million.

In the second quarter of 2007, we paid dividends to the Province of Ontario in the amount of $73 million, consisting of $68 million in common dividends and $5 million in preferred dividends. In the comparative period, we paid common dividends of $59 million and preferred dividends of $5 million. Year-to-date, we have paid common and preferred dividends totaling $180 million, compared to $223 million in 2006.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	2007	2006	$ Change	% Change	2007	2006	$ Change	% Change
Transmission	155	97	58	60	250	197	53	27
Distribution	138	100	38	38	229	175	54	31
Other	10	1	9	900	11	3	8	267
	303	198	105	53	490	375	115	31

Transmission

Transmission capital expenditures increased by $58 million, or 60%, to $155 million in the second quarter, and increased by $53 million, or 27%, to $250 million in the first six months, compared to the same periods in 2006. Expenditures made to expand and reinforce our transmission system were $89 million in the quarter and $136 million for the first six months of the year, representing increases over the comparative periods of $58 million and $52 million, respectively. These increases primarily reflect load and generation connections work at our Whitby and London Talbot transformer stations, and the reconfiguration of our Lambton Transformer Station. Our expenditures on major lines and stations development projects have also increased as a result of construction on our new inter-connection with Quebec, which will increase access to emission-free hydroelectric power, work at our Cambridge Preston Transformer Station, and the continued construction of our Downtown Toronto Cable Project. The impact of these increases was partially offset by expenditures on our Niagara Reinforcement Project, which was substantively completed last year. Final completion continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions continue between the affected aboriginal peoples and the various government entities involved. Expenditures to sustain our existing transmission system were $51 million in the quarter and $92 million on a year-to-date basis, representing reductions of $4 million and $2 million respectively, compared to the same periods last year. Our other transmission capital expenditures were $15 million in the quarter and $22 million for the first six months, representing respective increases of $4 million and $3 million, primarily due to expenditures on a major business systems and processes project.

Distribution

Distribution capital expenditures increased by $38 million, or 38%, to $138 million in the quarter and by $54 million, or 31%, to $229 million for the first six months, compared to the same periods in 2006. Capital investments to expand and reinforce our distribution network were $71 million in the quarter and $109 million for the first six months, representing increases of $32 million and $37 million over the comparable periods. These increases primarily reflect our ongoing investments in smart meters. During the quarter, we installed about 60,000 smart meters, for a year-to-date total of approximately 89,000 and a cumulative program total of approximately 117,000. We plan to install about 240,000 smart meters in 2007. Expenditures to sustain our distribution system of $56 million in the quarter and $96 million year-to-date, increased by $3 million and $7 million respectively compared to last year. These increases were primarily due to higher end-of-life planned replacement expenditures in our lines work program and the impact of replacing storm damaged components in the second quarter. Other capital expenditures increased to $11 million and $24 million for the three and six month periods compared to $8 million and $14 million in the same periods last year as a result of higher information technology expenditures, including expenditures on a major business systems and processes project.

Other

Other capital expenditures made to enhance our telecom infrastructure increased by $9 million in the second quarter and by $8 million in the first six months compared to the same periods in 2006. These increases were largely due to construction of a dedicated optical network which will provide secure, high capacity connectivity across numerous healthcare locations in Ontario.

Future Capital Expenditures

Our capital expenditures are planned to be about $1.25 billion in 2007 and $1.35 billion in 2008. These planned investments will address new development and supply enhancement initiatives, including system expansions, generation requirements and load connections, and the needs of our aging transmission system under continued challenging conditions of generation supply. Our transmission rate application, which was filed in the third quarter of 2006, reflected these prudent transmission infrastructure project investments in a secure and reliable transmission system, consistent with the public interest. Within our distribution business, the mass deployment of smart meters is underway and we are currently on track to meet the 2007 year-end target. Our future capital expenditures also include a major business systems and processes project, which incorporates the replacement of end of life information systems.

The Ontario Power Authority (OPA) is responsible for developing the Integrated Power System Plan (IPSP) and submitting it to the OEB for review and approval. The OPA is expected to submit the IPSP to the OEB in 2007. We intend to proceed with some transmission projects in the short-term because of pressing need, consistent with our transmission rate application. The IPSP is expected to influence the amount of our future capital expenditures. The timing of many of our development projects is dependent upon the final IPSP, the requirement for approvals from various regulatory bodies, and requirements for negotiations and consultations with customers, neighbouring utilities and other stakeholders and our ability to effectively resource these projects. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Our distribution investment plan includes the mass rollout of the smart metering program. Over the period 2007 to 2010, we anticipate installing 1.3 million meters throughout our service territory. Consistent with the government policy, all homes and small businesses are to receive a smart meter by the end of 2010. Total project costs are anticipated to be significant. In 2007, we plan to invest approximately $75 million under our smart meter program. At the Province's request, we will review our implementation plan and associated costs for the period 2008 to 2010.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments.

June 30, 2007 (Canadian dollars in millions)	Total	2007[1]	2008/2009	20010/2011	After 2011
Contractual Obligations *(due by year)*					
Short-term note payable	75	75	-	-	-
Long-term debt – principal repayments	5,388	113	900	650	3,725
Long-term debt – interest payments	5,208	153	563	487	4,005
Inergi LP outsourcing agreement[2]	448	56	195	181	16
Operating lease commitments	16	3	10	2	1
Total Contractual Obligations	11,135	400	1,668	1,320	7,747
Other Commercial Commitments *(by year of expiry)*					
Bank line[3]	750	750	-	-	-
Letters of credit[4]	107	97	10	-	-
Guarantees[4]	275	275	-	-	-
Pension[5]	257	49	200	8	-
Total Other Commercial Commitments	1,389	1,171	210	8	-

[1] The amounts disclosed represent the balance due over the period July 1, 2007 to December 31, 2007.

[2] On March 1, 2002, Inergi LP began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[3] As a backstop to our commercial paper program, we have a $750 million, 364-day revolving standby credit facility with a syndicate of banks. The term of this facility has been extended as of August 10th, 2007 to August 10th, 2010.

[4] We currently have bank letters of credit of $93 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of $10 million and parental guarantees of $275 million. Pursuant to Market Rule changes which became effective August 1, 2007, we are now able to meet our entire prudential support obligation using only parental guarantees based on our highest long-term credit rating which is in the "Aa" category. Although no letters of credit are required for prudential support as of August 1, 2007, we would have to resume providing bank letters of credit if our credit rating deteriorated. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[5] Contributions to the pension fund are made one-month in arrears. Contributions for 2007 will be based on an actuarial valuation effective December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, we currently estimate our annual pension contributions for 2007 and beyond to be up to $100 million.

The amounts in the above table under long-term debt are not charged to our results of operations, but are reflected on our balance sheet and statement of cash flows. Interest associated with this debt is recorded under financing charges on our statement of operations or in our capital programs, but these financing charges are not reflected in the above table. Payments in respect of operating leases and our outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our statement of operations or in our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder the Province of Ontario. The year-over-year changes in these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the Ontario Electricity Financial Corporation.

RECENT DEVELOPMENTS

Transmission and Distribution Rate Applications

During the second quarter, the evidentiary phase of the transmission rate hearing was completed and we filed our final argument with the OEB on June 13, 2007. Based on the OEB's processing guidelines, a decision is anticipated shortly.

We are currently in the process of preparing our 2008 distribution rate application for our subsidiary Hydro One Networks. On July 18, 2007, we held a stakeholder session which was attended by interested parties and we highlighted some of the key aspects of our application. We are required to file our application with the OEB by August 15, 2007.

Combined Smart Meter Proceeding

On May 2, 2007, the OEB issued a notice for a combined proceeding to determine certain general principles related to the prudence and recovery of costs associated with smart metering activities. Our subsidiaries, Hydro One Networks and Hydro One Brampton Networks participated in this proceeding. During June 2007, evidence was filed by our subsidiaries and an oral hearing was held. On August 8, 2007, the OEB issued a decision approving the recovery of expenditures associated with the minimum functionality for advanced metering infrastructure.

Society Negotiations

In April 2007, we commenced early bargaining for the next collective agreement with the Society of Energy Professionals (Society) and on May 31, 2007 we successfully reached a tentative agreement with a five-year term effective April 1, 2008. In June 2007, the collective agreement was ratified by our Board of Directors and the Society.

Application to Construct Facilities

On June 6, 2007, the Minister of the Environment issued a letter confirming an individual environmental assessment (EA) is not required for the Holland Transformer Station Project which proposes construction of a new transformer to address ongoing load growth in northern York Region. The letter grants approval of the EA subject to certain conditions. We anticipate the project to be in-service in Spring 2009.

In the first quarter, we filed leave-to-construct applications for our Western Brampton Line Reinforcement and our Supply to Woodstock projects. These applications are awaiting OEB review pursuant to the Transmission System Code in relation to the treatment of capital contributions for local area supply connection facilities. Decisions are anticipated in August 2007.

Purchase of Assets

On July 9, 2007, we entered into an agreement with the Township of Terrace Bay to purchase the assets of Terrace Bay Superior Wires Inc. (TBSW) for approximately $1 million. TBSW is located on the north shore of Lake Superior and has approximately 950 customers. The transaction is subject to OEB approval and on July 11, 2007 we submitted a joint application, with the Township of Terrace Bay, to the OEB. The transaction is anticipated to close in Fall 2007.

SELECTED FINANCAL HIGHLIGHTS AND RATIOS

(Canadian dollars in millions) (except as otherwise noted)	Three months ended June 30		Six months ended June 30	
	2007	**2006**	**2007**	**2006**
Net income	93	99	242	251
Net cash from operating activities	238	218	537	364
Capital expenditures	303	198	490	375
Earnings per common share *(Canadian dollars)*	888	943	2.334	2.417
Earnings coverage ratio[1]			2.77	2.71
Net asset coverage on long-term debt[2]			1.91	1.92
Total debt to capitalization[3]			52%	52%

[1]The earnings coverage ratio has been presented for the twelve months ended June 30, 2007 and June 30, 2006, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2]The net asset coverage on long-term debt ratio has been presented as at June 30, 2007 and December 31, 2006 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt including current portion.

[3]Total debt to capitalization ratio has been presented as at June 30, 2007 and December 31, 2006 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this Management's Discussion and Analysis, often contain forward looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements regarding future capital expenditures; statements about the installation and cost of smart meters; expectations surrounding future pension contributions; statements regarding potential incremental environmental expenditures; and expectations concerning the impact of new accounting standards. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward looking statements, whether written or oral, or whether as a result of new information, future events or otherwise, except as required by law.

These forward looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; and no significant events occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final IPSP, as approved by the OEB;
- delays or denials of the requisite approvals for planned future capital expenditures;
- regulatory decisions regarding our revenue requirements and tariff rates;
- significant changes to Environment Canada's draft PCB regulations issued on November 4, 2006; and
- future interest rates, inflation, changes in benefits and changes in actuarial assumptions.

We caution the reader that the above list of factors is not exhaustive.

This management's discussion and analysis is dated as at August 10, 2007. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2007	2006	Six months ended June 30 2007	2006
Revenues				
Transmission *(Note 3)*	315	316	642	614
Distribution *(Note 4)*	798	757	1,742	1,613
Other	7	5	14	11
	1,120	1,078	2,398	2,238
Costs				
Purchased power	522	505	1,163	1,103
Operation, maintenance and administration *(Note 4)*	259	234	493	419
Depreciation and amortization *(Note 2)*	129	127	254	245
	910	866	1,910	1,767
Income before financing charges and provision for payments in lieu of corporate income taxes	210	212	488	471
Financing charges	74	73	147	146
Income before provision for payments in lieu of corporate income taxes	136	139	341	325
Provision for payments in lieu of corporate income taxes	43	40	99	74
Net income	93	99	242	251
Other comprehensive income	1	-	1	-
Comprehensive income *(Note 2)*	94	99	243	251
Basic and fully diluted earnings per common share *(Canadian dollars)*	888	943	2,334	2,417

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2007	2006	Six months ended June 30 2007	2006
Retained earnings, beginning of period	1,226	1,072	1,184	1,079
Net income	93	99	242	251
Dividends *(Note 5)*	(73)	(64)	(180)	(223)
Retained earnings, end of period	1,246	1,107	1,246	1,107

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (unaudited)

(Canadian dollars in millions)	June 30, 2007	December 31, 2006
Assets		
Current assets		
Accounts receivable (net of allowance for doubtful accounts)	769	777
Materials and supplies	62	56
Other	7	13
	838	846
Fixed assets		
Fixed assets in service	16,322	16,238
Less: accumulated depreciation	6,164	6,180
	10,158	10,058
Construction in progress	667	468
	10,825	10,526
Long-term assets		
Deferred pension asset	383	382
Regulatory assets	251	311
Goodwill	133	133
Long-term accounts receivable and other assets	7	12
	774	838
Total assets	12,437	12,210
Liabilities		
Current liabilities		
Bank indebtedness	15	29
Accounts payable and accrued charges	649	661
Accrued interest	52	49
Short-term notes payable	75	60
Long-term debt payable within one year *(Note 6)*	612	395
	1,403	1,194
Long-term debt *(Note 6)*	4,764	4,848
Other long-term liabilities		
Regulatory liabilities *(Note 3)*	502	473
Employee future benefits other than pension *(Note 7)*	830	803
Environmental liabilities	51	55
Long-term accounts payable and other liabilities	15	16
	1,398	1,347
Total liabilities	7,565	7,389
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,246	1,184
Accumulated other comprehensive income *(Note 2)*	(11)	-
Total shareholder's equity	4,872	4,821
Total liabilities and shareholder's equity	12,437	12,210

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2007	2006	Six months ended June 30 2007	2006
Operating activities				
Net income	93	99	242	251
Adjustments for non-cash items:				
Depreciation and amortization (net of removal costs)	116	118	231	227
Retail settlement variance accounts	-	3	16	6
Transmission earnings sharing	-	3	-	18
Amortization of discount	3	7	6	18
Low-voltage services	-	(2)	-	(8)
	212	228	495	512
Changes in non-cash balances related to operations	26	(10)	42	(148)
Net cash from operating activities	238	218	537	364
Financing activities				
Long-term debt issued	-	250	400	550
Long-term debt retired	(282)	(448)	(282)	(448)
Short-term notes payable	75	130	15	130
Dividends paid	(73)	(64)	(180)	(223)
Other	-	(4)	(1)	(4)
Net cash (used in) from financing activities	(280)	(136)	(48)	5
Investing activities				
Fixed assets	(303)	(198)	(490)	(375)
Other assets	15	1	15	9
Net cash used in investing activities	(288)	(197)	(475)	(366)
Net change in cash and cash equivalents	(330)	(115)	14	3
Cash and cash equivalents, beginning of period	315	109	(29)	(9)
Cash and cash equivalents, end of period	(15)	(6)	(15)	(6)

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

These interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) for the year ending December 31, 2006 which includes information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements, except as described below in note 2.

The demand for electricity generally follows normal weather-related variations, and therefore the Company's energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

2. ACCOUNTING CHANGES

Change in Accounting Policy – Financial Instruments, Hedges and Comprehensive Income

Effective January 1, 2007, the Company adopted four new accounting standards comprising the Canadian Institute of Chartered Accountants' (CICA) Handbook Sections 1530, *Comprehensive Income*; 3855, *Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation*; and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that are recorded in opening accumulated other comprehensive income (AOCI) as described below, consistent with the CICA Handbook sections. The comparative interim Consolidated Financial Statements have not been restated. The principal changes in the accounting for financial instruments and hedges due to the adoption of these accounting standards are described below.

(a) Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date. The impact of this amortization is immaterial to the Statement of Operations.

(b) Financial Assets and Liabilities

Under the new standards, all financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the consolidated balance sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Short-term investments	Held-to-maturity
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (excluding MTN Series 8 Note)	Other liabilities
MTN Series 8 Note	Designated as held-for-trading

The MTN Series 8 Note is a step-up coupon note with a maturity date in 2007, and with extended maturity dates up to 2011.

Where there is an economic hedge, as in the case of the MTN Series 8 note and associated interest rate swap, we have applied the fair value option without hedge accounting. The impact is not material.

All financial instrument transactions are recorded at trade date.

(c) Derivatives and Hedge Accounting

Derivatives

All derivative instruments, including embedded derivatives, are carried at fair value on the balance sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The impact of the change in the accounting policy related to embedded derivatives was not material.

Hedge Accounting

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documents the relationship between the hedging instrument and the hedged item. This would include linking all derivatives to specific assets and liabilities on the consolidated balance sheet or to specific firm commitments or forecasted transactions. The Company would also assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used are effective in offsetting changes in fair values or cash flows of hedged items.

Upon adoption of the new standards, the Company reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to accumulated other comprehensive income. The hedging losses are amortized through OCI using the effective interest method over the term of the hedged debt.

(d) Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading, are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method. The impact of the change in amortization method from an annuity basis to the effective interest method was not material.

Change in Accounting Estimate – Depreciation

Effective January 1, 2007, the Company prospectively revised its fixed asset depreciation rates resulting from a periodic external review required by the Ontario Energy Board (OEB). Capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis. The estimated impact of the change in rates is a reduction in depreciation expense of approximately $7 million per annum. A summary of the new rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Transmission	1% - 4%	2%
Distribution	1% - 13%	2%
Communication	1% - 13%	5%
Administration and service	1% - 20%	8%

3. TRANSMISSION EXCESS EARNINGS SHARING MECHANISM

On March 30, 2007, the OEB issued a decision ordering that the transmission earnings sharing mechanism cease effective December 31, 2006. The balance of the account was $35 million. After OEB review, the approved balance of this account, including interest, is expected to be incorporated into future rates to be set later in 2007. In its decision, the OEB also ordered that the Company establish a new regulatory deferral account to record the revenue differential between existing transmission rates and the new rates that are anticipated to be approved later in the year. The new deferral account will represent the revenue differential between existing and future rates for the period between January 1, 2007 and the date of the OEB's upcoming transmission rate decision. As the specifics of this decision cannot be foreseen, the value of this account cannot reasonably be determined at this time. Appropriate accounting recognition will be given to any revenue differential once the OEB renders its decision on Hydro One's transmission rates.

4. SMART METER COST RECOVERY

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine the recovery of costs incurred by distributors. Expenditures associated with the minimum functionality for advanced metering infrastructure were approved for recovery. Consequently, as at June 30, 2007, the Company reduced its net smart meter regulatory asset and recorded fixed assets of $41 million. In addition, the Company recognized revenues of $10 million and an equivalent amount of costs incurred in support of the program which were deferred in previous periods. Costs determined to be above the minimum functionality will be brought forward for review in a subsequent cost of service rate application.

5. DIVIDENDS

During the three months ended June 30, 2007, preferred dividends in the amount of $5 million (2006 - $5 million) and common dividends in the amount of $68 million (2006 - $59 million) were declared. During the six months ended June 30, 2007, preferred dividends in the amount of $9 million (2006 - $9 million) and common dividends in the amount of $171 million (2006 - $214 million) were declared.

6. LONG-TERM DEBT

On March 13, 2007, Hydro One issued notes under the Company's medium term note program. The issue was comprised of medium term notes with a principal amount of $400 million having a 30-year term with a coupon rate of 4.89%. The notes are due March 13, 2037.

In the second quarter, Hydro One extended the maturity date of its $40 million extendible step-up note from May 15, 2007 to November 15, 2007.

The Company has a $750 million, 364-day revolving standby credit facility with a syndicate of banks. The term of this facility has been extended as of August 10th, 2007 to August 10th, 2010.

7. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2007**	**2006**	**2007**	**2006**
Pension				
Net periodic benefit cost	25	39	50	77
Pension fund contribution	26	22	51	44
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	10	9	20	17
Portion attributable to regulatory assets	-	3	-	11
Charged to results of operations	16	10	31	16
Employee Future Benefits Other than Pension				
Net periodic benefit cost	26	31	53	61
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	11	9	21	19
Charged to results of operations	15	22	32	42

8. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- An "other" segment primarily consisting of telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended June 30 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2007				
Segment profit				
Revenues	315	798	7	1,120
Purchased power	-	522	-	522
Operation, maintenance and administration	107	145	7	259
Depreciation and amortization	60	67	2	129
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	148	64	(2)	210
Financing charges				74
Income before provision for payments in lieu of corporate income taxes				136
Capital expenditures	155	138	10	303
2006				
Segment profit				
Revenues	316	757	5	1,078
Purchased power	-	505	-	505
Operation, maintenance and administration	109	120	5	234
Depreciation and amortization	61	64	2	127
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	146	68	(2)	212
Financing charges				73
Income before provision for payments in lieu of corporate income taxes				139
Capital expenditures	97	100	1	198

Six months ended June 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2007				
Segment profit				
Revenues	642	1,742	14	2,398
Purchased power	-	1,163	-	1,163
Operation, maintenance and administration	206	273	14	493
Depreciation and amortization	120	131	3	254
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	316	175	(3)	488
Financing charges				147
Income before provision for payments in lieu of corporate income taxes				341
Capital expenditures	250	229	11	490
2006				
Segment profit				
Revenues	614	1,613	11	2,238
Purchased power	-	1,103	-	1,103
Operation, maintenance and administration	202	206	11	419
Depreciation and amortization	120	122	3	245
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	292	182	(3)	471
Financing charges				146
Income before provision for payments in lieu of corporate income taxes				325
Capital expenditures	197	175	3	375

(Canadian dollars in millions)	June 30, 2007	December 31, 2006
Total assets		
Transmission	7,085	6,950
Distribution	5,256	5,161
Other	96	99
	12,437	12,210

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

9. COMMITMENTS

Purchasers of electricity in Ontario, through the Independent Electricity System Operator (IESO), are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees should the Company's subsidiaries, Hydro One Networks Inc. or Hydro One Brampton Networks Inc., fail to make a payment required by a default notice issued by the IESO.

On June 28, 2007, the IESO approved revisions to the prudential support obligations under the market rules. Previously, prudential support was provided to the IESO using a combination of bank letters of credit and parental guarantees. Under the new rules, effective August 1, 2007 the Company can meet its prudential support requirements using only parental guarantees, as long as it maintains a long-term credit rating in the "Aa" category. Consequently, the Company will reduce its bank letters of credit by $10 million.

10. SUBSEQUENT EVENT

On August 2, 2007, the Company entered into a forward starting pay fixed interest rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. This transaction had a notional amount of $150 million and is used to lock in the interest rate of a forecasted debt issuance planned for later in 2007. This transaction is being accounted for as a cash flow hedge of a forecasted transaction.

11. COMPARATIVE FIGURES

The comparative unaudited interim Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the June 30, 2007 unaudited interim Consolidated Financial Statements.